THE STATE OF NEW HAMPSHIRE
PUBLIC UTILITIES COMMISISON

DE 16-576

ELECTRIC DISTRIBUTION UTILITIES

Development of New Alternative Net Metering Tariffs and/or
Other Regulatory Mechanisms and Tariffs for Customer-Generators

City of Lebanon, NH

Direct Testimony of Clifton C. Below

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I. Introduction

Q. Please state you name, business address and position with regard to the docket.

A. My name is Clifton C. Below and my office address is 1 Court Street, Suite 300, Lebanon, NH 03766. I am a Lebanon City Councilor and Chair of the Lebanon Energy Advisory Committee created by the Council. Earlier this year the Lebanon City Council voted unanimously to authorize me to represent the City in this proceeding, as well as in IR 15-296, Investigation into Grid Modernization, on a volunteer basis.

Q. Please describe your background and experience with regard electric utility regulation and energy policy.

A. My interest in electric power and utilities began when I toured hydroelectric and nuclear power stations on the Susquehanna River while in Elementary School. That inspired me to try to construct a hand cranked electric generator out of wood, wire and magnets for a science fair in 6th grade. While the needle on the meter I installed wiggled back and forth, I think that was more from vibration of the contraption than actual AC current. In 1980 I graduated from Dartmouth College with distinction in my major of Geography and Environmental Studies. My course work included New England Energy Futures, Environmental Systems, Environmental Policy Formulation, and engineering courses in Community Systems (e.g. electric and water utilities) and Principles of Systems Design. In 1985 I earned an M.S. in Community Economic Development from Southern NH University, with course work in such areas as accounting, financial and organizational management, financing, and business development. During this time I became a sweat-equity partner in the development of two commercial buildings on urban renewal parcels that helped to revitalize downtown Lebanon. I continue to operate and manage one of those two buildings and with a modicum of success in that regard it enabled to begin serving in the New Hampshire legislature for 12 years starting in 1992 and do this volunteer work.

At the start of my first term I was appointed to the House Science Technology and Energy Committee. The first study committee that I was appointed to was the “Small Power Producers and PSNH Renegotiations Legislative Oversight Committee” that gave me a crash course into LEEPA and PURPA issues, as well as the tension between competition and regulation, as over-market contracts with independent power producers (QFs) were being renegotiated. Those contracts and the PUC rate order approving them were originally justified by the same load and rate projections that were used to justify continued investment in the Seabrook nuclear station.

In 1995 I Chaired the Policy Principles, Social and Environmental Issues Subcommittee of the Retail Wheeling and Restructuring Study Committee. In that role, I worked closely and collaboratively with then ST&E Chair Rep. Jeb Bradley and many other legislators and stakeholders to craft a consensus report and recommendations that became the foundation for NH's Electric Utility Restructuring statute, RSA 374-F, the enactment of which enjoyed broad bi-partisan support. In 1996 Rep. Bradley and I provided joint written and in-person testimony before the Energy & Power Subcommittee of the U.S. House Committee on Commerce on State-Federal issues related to electric utility restructuring on behalf of the NH House of Representative. In 1997 I sponsored HB 485 with my co-sponsor Rep. Bradley that reformed the NH LEEPA statute, RSA 362-A, and first established net energy metering in New Hampshire in 1998.

After I was elected to the New Hampshire State Senate in 1998 I was approached by Attorney Tom Rath and the CEO of Northeast Utilities and was asked to be the prime sponsor of (then controversial) securitization legislation that NU saw as critical to resolving PSNH's litigation against NH's electric utility restructuring. I did so and in 2000 I was part of the team that negotiated a resolution of PSNH's litigation with the enactment of RSA 369-B with strong bipartisan support that enabled restructuring to proceed in New Hampshire. Throughout my 12 year tenure in the legislature I always served on the policy committees that dealt with energy and electric utility issues and became active in regional and national forums. For example, from 1997-2004 I served on the Advisory Council on Energy of the National Conference of State Legislatures (NCSL), including 3 years as Chair and the Energy & Electric Utilities Committee, Assembly on Federal Issues, where, as Chair in 2000-2001, I facilitated a consensus based comprehensive update of NCSL's National Energy Policy (and other policies) used for lobbying the federal government on behalf of all state legislatures. I testified before the United States Senate Committee on Energy and Natural Resources on "Electric Industry Restructuring," with a particular focus on transmission issues, on behalf of NCSL. I also served as a member of the National Council on Electricity Policy, Steering Committee from 2001-2004.

After not seeking reelection to the State Senate Governor Lynch nominated me to the NHPUC, where I served over 6 years as a Commissioner from the end of 2005 into 2012. I read reams of testimony, participated in examination of witnesses and the adjudication of some 360 cases with public hearings. I was active in ISO New England stakeholder processes and other regional and national forums on behalf of the NHPUC and the State. I served on the National Association of Regulatory Utility Commissioners (NARUC) Energy Resources & Environment Committee for 6 years including 3 as a Vice-Chair. I also served on the FERC-NARUC Smart Grid and Demand Response Collaborative, 2008-2011 and on the Electric Power Research Institute (EPRI) Advisory Council, 2009-2011 and its Energy Efficiency/Smart Grid Public Advisory Group, 2008-2010. I also served as President of the New England Conference of Public Utility Commissioners (NECPUC) from 9/2010 to 9/2011. A more detailed statement of my background and experience is attached as Appendix A.

II. Overview of Issues and Summary of Proposal

Q. What is the City of Lebanon's interest in future net metering tariffs?

A. In 2012 the Lebanon Planning Board and City Council adopted an updated Master Plan with an Energy Chapter that serves as official public policy for the City. Our Master Plan calls for Lebanon to be "a leader in energy efficiency, renewable energy reliance, and innovation across municipal, commercial, institutional, and residential sectors."[1] A key outcome is for the City to rely "upon as much local renewable energy as possible" (p. 13-18) and our strategies include pursuit of opportunities on City sites and encouraging the residential and business sectors to invest in renewable energy. Our purpose is to reduce both the carbon impact and the long-term cost of our energy consumption and to make our energy systems more resilient and sustainable to support the long-term prosperity of our local economy and the City.

Specifically the City has a number of sites suitable for net metered and group net metered facilities including the possibility of generating up to 1 MW from landfill gas that is

[1] From p. 13-17 of City of Lebanon Master Plan, 2012. Energy Chapter available at: http://planning.lebnh.net/home/master-plan/implementation/chapter-13.

now being flared, and so is ready to convert to power production, and on the order of 2 MW or more of potential solar PV sites, as well as a bit of hydro, some potential for heat led combined heat and power production, and some significant storage and demand response opportunities, all of which largely depend on net metering tariffs being developed in this docket. Lebanon is an electric customer of Liberty Utilities with approximately 85 meters and accounts and consumes approximately 5 million kWh per year. We estimate that within a couple of years we could be producing roughly twice what the City itself consumes from renewable resources on City sites.

During the course of 2015 one thing that LEAC and the City did in furtherance of its objectives to support residential investment in renewable energy was to support a "Solarize Lebanon-Enfield" effort, that, although sidetracked by Liberty Utilities' hitting its net metering cap, has resulted in an increase in small PV installations in the City, from about 16 to 46 and from about 81 kW installed capacity at the start of the program to approximately 320 kW or more now, a four-fold increase. One of the things that we learned from this experience, besides the need for stable net metering policies, is that there are a significant number of residents who would like to invest in or purchase solar power, but do not have suitable sites at their own homes, hence indicating a need and opportunity for community solar projects.

Q. As the original sponsor of NH's net metering legislation nearly 20 years ago, generally how do you view the expectations set forth in HB 1116, Chapter 31, Laws of 2016 that initiated this proceeding?

A. After the Solarize Lebanon-Enfield campaign was stopped dead in its tracks last summer by the interconnection cap, I got involved in both DE 15-271, concerning queue management for interconnection of net metered customer-generators, and the development of the legislation that became Chapter 31, NH Laws of 2016. I testified in support of HB 1116 and its Senate companion bill in both chambers. As both Sen. Bradley and I stated at those hearings, the original net metering statute was recognized as a rough justice for early adopters of emerging renewable technologies for behind the meter generation. Today, we are past the early adopter stage as distributed renewable generation has become more cost-effective and popular as an important means to act to reduce the climate risk from burning fossil fuels and promote energy independence and local resources. We need a net metering policy that results in a more refined and granular justice for all involved.

It is important to view the work in this docket in the context of the purpose statement in Chapter 31:1, which starts by stating that to “meet the objectives of electric industry restructuring pursuant to RSA 374-F, including the overall goal of developing competitive markets and customer choice to reduce costs for all customers . . . the general court finds that it is in the public interest to continue to provide reasonable opportunities for electric customers to invest in and interconnect customer-generator facilities” while ensuring fairness in the allocation of costs and benefits. It goes on to state that the “general court continues to promote a balanced energy policy that” promotes “a modern and flexible electric grid that provides benefits for all ratepayers” among other things.

This proceeding, and I believe the City of Lebanon’s proposal for piloting a real time net metering tariff set forth below, is an opportunity to significantly advance some of the yet to be fully realized goals of RSA 374-F in a way that will benefit all utility customers and the resiliency of the electric grid and industry itself.

Q. Could you elaborate on those “yet to fully realized goals of RSA 374-F” and how that relates to the City’s proposal?

A. Yes. I think it will be helpful to consider some of goals and principles expressed in RSA 374-F, enacted into law over 20 years ago, to help inform the weight to be given to various rate design principles in evaluating proposed tariffs in this case (with emphasis added):

> **374-F:1 Purpose. –**
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> I. The most compelling reason to restructure the New Hampshire electric utility industry is to **reduce costs for all consumers of electricity by harnessing the power of competitive markets**. The overall public policy goal of restructuring is to develop a more efficient industry structure and regulatory framework that results in a more productive economy by reducing costs to consumers while maintaining safe and reliable electric service with minimum adverse impacts on the environment. **Increased customer choice and the development of competitive markets for wholesale and retail electricity services are key elements in a restructured industry** . . .
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> II. A transition to competitive markets for electricity is consistent with the directives of part II, article 83 of the New Hampshire constitution which reads in part: "Free and fair competition in the trades and industries is an inherent and essential right of the people and should be protected against all monopolies and conspiracies which tend to hinder or destroy it." **Competitive markets should** provide electricity suppliers with incentives to operate efficiently

and cleanly, **open markets for new and improved technologies**, **provide electricity buyers and sellers with appropriate price signals**, and improve public confidence in the electric utility industry."

374-F:3 Restructuring Policy Principles. – . . .

II. Customer Choice. . . . **Customers should be able to choose among options such as** . . . **real time pricing,** and generation sources including interconnected self generation . . . ."

While good rate and tariff design requires the balancing of a variety of principles and objectives, New Hampshire policy clearly gives considerable weight to customer choice, the development of competitive markets, including, of note, for **retail** electricity services, and the provision of "appropriate price signals." In this context it seems apparent that "appropriate price signals" include those that achieve economic and operational efficiency and help achieve express public policy goals such as "maintaining safe and reliable electric service with minimum adverse impacts on the environment." New Hampshire statutory policy calls out specifically for customers to have the choice of real time pricing. Even as that concept and practice was still relatively new and limited to wholesale markets two decades ago, it was apparent to legislators that enabling retail load (customers) to respond to temporal price signals in supply markets is important to economic efficiency and productivity. While considerable effort has gone into developing wholesale supply markets in New England, we can do a better job connecting wholesale market price signals to retail consumption and supply markets and enabling small customers and customer-generators to have greater participation in retail electricity market choices.

Q. Are there other rate design principles that inform your testimony?

A. Yes, many of the principles first developed by James Bonbright and Alfred Kahn remain relevant today. Rates should yield the revenue required for regulated monopoly services in a stable and predictable manner. Rates should reflect cost causation, avoid undue discrimination and fairly apportion costs among customer classes, and, I'd say increasingly, in this day and age, among individual customers. Furthermore rates should promote economically efficient consumption and investment, and promote innovation in supply and demand. Rates that are forward looking and reflect marginal costs, especially long-term marginal costs when long-term investments are involved, can efficiently harmonize utility and customer investments, choices and benefits. Better translating existing wholesale market prices signals for both generation services and transmission services to load could be key in this regard.

Q. Could you summarize your alternative net metering tariff proposals?

A. Yes, first I'll summarize what would be ideal, but can't be implemented in the near term due to limitations of current utility metering and billing systems. Then I'll summarize our proposed work-around in the form of a real time pricing (RTP) net metering (NM) pilot. Finally I'll summarize some recommendations for new NM tariffs that can work with existing meters and billing systems as a part of default service. More detailed discussions then follow.

Ideally a RTP NM tariff option would be offered on an opt-in basis as a secondary form of default service. During each RT interval when power is exported to the distribution grid it would receive credit at NH load zone Real Time Locational Marginal Prices (RTLMPs) plus all generation related ancillary services that are also billed with LMPs (and hence avoided when the load at the wholesale meter point is turned down from what it would otherwise be), adjusted for avoided line losses. Likewise, whenever power is imported from the grid it would be charged at the same RT Prices (RTPs) plus a mark-up to cover related billing and overhead (but not hedging services). Likewise FCM charges would be incurred or credited as avoided, based on the net load or production at the hour of New England wide coincident peak (CP) for each year.

Monthly transmission charges that are based on the monthly CP (of the "local" transmission network, either the whole NU or National Grid system in New England in NH's case), would be charged or credited based on each RTP NM customer's actual load during those monthly CPs. Distribution rates would be modified on a revenue neutral basis so that each customer class' composite or average load profile would produce the same revenue, but demand charges would be either based largely on share of CP, or customer peak on limited number of hours that are highly likely to be when the coincident peak occurs in a given year. Volumetric distribution rates would likewise be modified in a revenue neutral manner so that most costs are recovered during a limited number of pre-defined hours when system peaks are most likely to occur, say when demand might exceed 90% of annual peak. There would be decoupling of the distribution revenue requirement from net changed volumetric load (and shifting demand) compared with assumed or forecast load.

In order to facilitate a **<u>RTP NM pilot work-around</u>** of existing utility metering and billing limitations, the Lebanon City Council voted unanimously on Oct. 5th to designate the Lebanon Energy Advisory Committee (upon LEAC's recommendation) as Lebanon's Electric Aggregation Committee pursuant to RSA 53-E:6, I to develop a plan for an aggregation program, subject to future approval by the Council. I've attached a copy of RSA 53-E for convenient reference as Appendix B. I'll return to the significance of this later. The pilot would work outside of default service. The pilot would be administered with the assistance of a competitive energy supplier, two of which have indicated a strong interest in working with the City if this is approved. RTP NM for supply would be provided similar to what is described above. Load above and beyond that produced by NM DG would also be available at RTPs plus a modest retail mark-up. Either a secondary revenue grade interval meter with communications or an upgrade to the existing utility meter would be paid for by participants as described in the next section. Secondary meter data would be made available to Liberty Utilities at no charge. Participation in PPAs or even direct investment in off-site DG such as for community solar would likely be available to participants.

Transmission and distribution services would continue to be directly billed by Liberty, but there would be a transmission tariff rider in which pilot participants, through their supply bill, would receive a credit or additional transmission charge for their interval measured percentage deviation from customer class average load shape, i.e. the percentage of their monthly load (or surplus generation) that occurs on the hour of monthly coincident peak. The sum of differences would be settled monthly with Liberty through their Transmission Cost Adjustment Mechanism (TCAM) reconciliation account. Either distribution charges would simply be billed monthly for any net loads consumed over the billing period by customers, with no credit for net monthly exports, or with a pilot tariff for coincident peak demand charges and/or TOU volumetric components, distribution charges could be incurred for any hour in which there is net consumption across a meter (instead of the whole month) with no or limited credit for exports. The City would need for this pilot to be approved for a long duration, say through 2040, as long-term investments in landfill gas generation, community solar and other NM DG facilities are anticipated, but the pilot could be limited to Lebanon and contiguous municipalities within Liberty Utilities' Lebanon area service territory.

For a new NM tariff that will work with existing default service and meters, considering the value of solar NM generation as I discuss in the respective sections below, I propose that a volumetric credit continue to be allowed to be carried forward for default service and transmission charges, but not for distribution services and other minor charges, at least for solar. However, a customer that generates and sells RECs for their entire production (as opposed to only their net annual exports) would pay an RPS compliance adder equal to that included in default service rates for any carried forward volumetric net metering credit. NM tariffs that work with default service are of interest to the City because some residents and businesses that may want to invest in NM renewable energy system, which we want to encourage, but may not want to participate in a RTP NM pilot, or wait for it to launch, even if it is approved.

III. Metering Issues

Q. How do current metering and information systems constrain options within this docket?

A. First and foremost, throughout the informal discovery processes that have preceded initial filings in this case, it has been apparent that the lack of interval data, including load research data concerning net metered and other customers has limited the analytical ability of the parties to better understand the temporal attributes and impacts of customer-generators compared with the diversity of load shapes and impacts of other customers. For instance there has been very little "before and after" load shape data on customer generators. The NH Electric Cooperative was able to undertake an analysis in support of new net metering tariffs that clearly and substantially benefited from a body of detailed customer interval data. For instance their "'Above the Cap' Net Metering Staff Analysis & Recommendations"[2] reports that "we found that, on average, we could attribute an increase in usage of about 52% to the PV accounts" (p. 3) negating some of what might otherwise be under-recovery of delivery charges. This seems to be evidence of PV adopters also adopting new forms of electrification, such as heat pumps and/or electric vehicles. The report also states that they "performed detailed analysis of the PV systems' contribution during each peak hour during the prior two

[2] http://www.nhec.com/filerepository/nhec_above_the_cap_net_metering_recommendationsstaff_analysis_2.pdf

years and concluded that, under current net metering, the annual demand related Regional Access [transmission] costs attributable to members with PV installations was reduced by 34%." (p. 4). Further "[d]etailed analysis of the last two summers determined that members with PV installations reduced their contributions to NHEC's load at the time of the FCM peak by 60%." (p. 5). They indicated that they planned to update these analyses annually.[3]

Recognizing that NHEC has indicated that they do not want to be involved in this proceeding, perhaps little weight can be given to their analysis, but it is indicative of the kind of analysis that is made possible with interval data that could be made available through a pilot such the City of Lebanon is proposing, in advance of widespread AMI deployment. The key here is to find a revenue grade metering solution that can be implemented on an affordable basis even for smaller accounts, such as for residential net metering, and it looks like competitive market forces are providing them. Existing interval metering options under utility tariffs are simply cost-prohibitive for all but the largest accounts. The current annual cost per meter for Liberty Utilities, for example, to retrieve, store and access interval data could cost up to $740-$772.[4]

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[3] A summary of resulting rates can be found at: http://www.nhec.com/filerepository/nhec__above_the_cap_net_metering_summary_2.pdf.

[4] Under **Liberty Utilities** Tariff No. 19, at p. 72, their "Optional Interval Data Service Provision" to subscribe to access to interval data over the internet requires an annual fee of $309 or $277 for each additional retail delivery account requested at the same time. However, this option also requires equipment (including a modem) to allow the utility to read the interval data over a telephone line for a one-time fee of $155 to $247. A basic dedicated phone line for this purpose through FairPoint can cost a total of about $38.55/mo. ($25.13 for a business line plus $13.42 in taxes and fees on local service) or about $463/year. Combined with the subscription charge this totals $740-$772/year. It may be possible that a dedicated phone line would not be necessary, or it might be obtained at less expense if part of a VOIP network, so the annual cost might be as low as the subscription cost, which is still a lot for a smaller accounts and would not provide anything resembling real time data.

Eversource does not have an annual subscription cost and instead only charges a one-time fee of $148 per phone line, that can read up to 5 meters at one location but they do require that "the Customer or Supplier provides and maintains a dedicated, dial-up, analog telephone line to the meter under their Tariff No. 9 at p. 34 under "Extended Metering Service." So this could cost about $463/year/phone line.

Unitil currently has a one-time cost of $220.11 for residential service (or $8.97 monthly) and $361.61 for general service (or $14.73 monthly) to obtain enhanced metering service that includes interval data and requires the customer at its own expense to install and operate telephone lines and service for the company to read the customer's meter. (Unitil Tariff No. 3, pp. 44-45) These lump sum costs are proposed to increase to $742.11 ($32.24 monthly) for residential service and $928.61 ($40.34 monthly) for general service in DE 16-384. It is not clear if the required phone line must be dedicated. For "Interval Data Service" (p. 46) where only Large General Service G1 customers can obtain web-based access to interval data (but then only after standard monthly data reads), there is an additional $335.05 monthly subscription fee (proposed to increase to $455.14 in DE 16-384).

Q. Short of waiting for utility roll-out of AMI, what work-around do you see for the high cost of simple interval data?

A. In contrast to the high cost utility options current available, technology and software innovation driven by market forces for lower cost sub-metering and DG monitoring and renewable energy credit production seems to have resulted in a variety of potential solutions, if customers, or a municipal aggregator, are allowed by this Commission to install a secondary revenue grade meter behind the utility meter on the customer premises. RSA 53-E:3, II(a) authorizes municipal aggregators to enter into agreements for "Meter reading" and "other related services" in the context of a statute whose purpose is to "allow municipalities to aggregate retail electric customers, as necessary, to provide such customers access to competitive markets for supplies of electricity and related services" finding "that aggregation may provide small customers with similar opportunities available to larger customers" and "to encourage voluntary, cost effective and innovative solutions to local needs." (RSA 53-E:1) There would be no point to authorizing independent meter reading services, just to get the same data that the utility already has and gives to customers, if a meter that was secondary or different from the one owned by the utility wasn't legally possible. Just to be clear though, the City of Lebanon is not opposed to working with Liberty to find an affordable upgrade that could be owned by them and used in their meter socket. However we are past the point when once a day dial-up telephone modems make sense for data retrieval, especially when near real time meter data solutions are available that can securely use existing communication networks. The City of Lebanon has already invested in a municipally owned fiber optic network that is located just below the electric lines on utility poles and connects all of the City's significant facilities. We have dark fiber that could be a cost-effective resource as part of a Liberty smart grid communications system.

At least one company, EKM Metering, Inc. offers an affordable revenue grade electrical meter and communications system that is designed to tie directly into local routers. Their EKM PUSH device securely pushes data to secure cloud storage once per minute, by default, but is capable of pushing real time data as often as once per second. For a one-time cost of $100 their system includes permanent secure storage and customer controlled secure access to data, with a very open and flexible API (applications programming interface). This approach to meter data is much like that recently approved by this Commission in REC 16-215 and REC 16-474 for

PowerDash, Inc. and Solar-Log. Attachment C is an affidavit from Jameson Brouwer, CTO of EKM Metering Inc. responding to a series of questions about their system that are relevant to how it might be used for this pilot.

Should this pilot be approved, the City likely would use a competitive procurement process, such as an RFQ or RFP, to select a revenue grade metering vendor and would work with the PUC and Liberty to see that any concerns can be addressed, assuming a Liberty provided solution can't be found. We recognize that third party metering, even for a pilot, may need a waiver or amendment to certain Puc 300 rules as they assume only the utility will provide metering services. Besides EKM, there are other meter providers who might provide viable alternatives, including Solar-Log[5] that has both socket and other meters than can use LAN or cellular networks and a company called Powercom.[6]

IV. Generation (Electricity Supply)

Q. If the City of Lebanon is proposing a pilot through which an aggregation program, in conjunction with a competitive electricity supplier is arranging to buy and sell electricity outside of default service, is any tariff or action needed by this Commission with regard to such transactions?

A. No, probably not. RSA 362-A:9, II does provide that: "Competitive electricity suppliers registered under RSA 374-F:7 may determine the terms, conditions, and prices under which they agree to provide generation supply to and purchase net generation output from eligible customer-generators." Puc 903.02(d) mimics this statutory provision. Of course other rate elements for net metering under such an arrangement still need to be addressed.

Q. With regard to a new default service NM tariff, wouldn't it just be simple and fair, to pay for any net exported electricity during any interval that can be metered or billed at PURPA avoided costs for QFs, while requiring customer-generators to buy back power at subsequent times or billing cycles at default service rates?

A. It might be simple, especially if RTLMPs are simply averaged, but I do not believe it would be fair. At least with regard to solar, which is, by far, the dominant technology used for

[5] http://www.solar-log-america.com/us/home.html
[6] http://www.powercom.co.il/Templates/PRODUCT/PRODUCT.aspx?folderid=129&lang=EN.

net metering,[7] and the only technology that I've seen hourly data for in New Hampshire, that would under value the contribution made by solar. The times that PV produces have tended, on average, to be distinctly above the average value for LMPs and ancillary services over the last 5 years according to available data. Comparing the value of solar for energy (RTLMPs plus ancillary services) plus capacity, using the annual Avoided Energy Cost calculations by NHPUC staff for purposes of Puc 903.02(i) to compensate annual net surplus generation, with the average value for all hours, it has been estimated that solar production occurs during hours that resulted in 35% higher value than average for the year ending 3/31/12, 19% higher for 2013, 13% higher for 2014, 12% higher for 2015, and 5% higher for 2016. These calculations however appear to substantially underestimate the value of solar because they used PV Watts modeled production for an assumed typical system, instead of actual PV production data. The PV Watts model uses typical weather data so it produces reasonably accurate projections of total average annual or even monthly production. It does this by using typical weather data drawn from actual historic dates. This necessarily results in a random mismatch of weather data, hourly solar insolation in particular, with actual conditions. High price hours in New England summers are correlated with high load hours, which in turn correlate with high solar insolation days which drive, in particular, air conditioning loads in building that heat up more when the sun shines.

For the 12 months ending 3/31/16 I used available actual data from 20 PV systems supplied by NESEA as part of informal discovery, plus 5 more systems that I collected data for, and ran them in the spreadsheet model attached hereto as my Schedules 1.1 through 1.3. My spreadsheets also used actual NH hourly values for generation related ancillary services instead of the $1/MWh that had been assumed by the staff calculation. The average percentage by which the value of PV production from these 25 systems exceeded the average of all hours was 27%, ranging from a low of 5% to a high of 67%. Obviously the 127% average value of solar is quite a bit more than the 105% value of solar compared with the average for all hours computed using modeled generation data. In addition I computed the load weighted average value for all hours of that year and this solar sample group still produced during hours that averaged 10%

[7] Note that PURPA rules do allow differentiation of compensation rates by technology: CFR § 292.304 (c)(3)(ii) provides that purchase rates "[m]ay differentiate among qualifying facilities using various technologies on the basis of the supply characteristics of the different technologies."

more in value and reached as high as 44% greater value. To the extent that a customer-generator either offsets their own load and/or generates surplus during higher than average hours, it means that their hours of net consumption will be significantly lower than what they would otherwise have been. In other words, the PV customer-generator appears, from this sample, to significantly improve their load profile, and hence that of the default service group that they are in, from a cost of energy service perspective. If they are not credited for the actual value of energy they produce, then any difference in value is being transferred to other default service customers, or possibly the default service provider or distribution utility.

I would like to note the significant diversity in the RT value of individual systems. Generally, western oriented and tracking systems produce at higher value times than more eastern oriented systems, yet current homogenized rates or credit mechanisms give no price signal in this regard. A significant part of this value is coincidence with FCM peak. For better economic efficiency more granular rates, specifically RTP, will create better price signals.

Q, Doesn't PURPA limit the authority of the NHPUC to require compensation of NM generation at more than PURPA avoided costs?

A. If an alternative NM tariff required the distribution utility to purchase exported power for resale, then it seems like it would; however that is not being proposed. Also, while a NM eligible customer-generator under NH law may qualify to be recognized as a QF under PURPA I don't believe that makes them QFs and subject to QF related provisions of PURPA if they are not seeking to sell power at wholesale to a utility for resale to other customers, as may be the case for required compensation for net surplus generation that is permanently sold to a utility. In fact, the federal Energy Policy Act of 2005 directed state utility commissions to consider implementing a net metering standard, if they hadn't already done so, which New Hampshire had. The current net metering statute and ones like it in other states have not been struck down as contrary to PURPA, logically since PURPA also calls for states to consider adopting such policies. It logically follows that this Commission can modify net metering into forms that may lie between the current full volumetric credit and compensation limited to PURPA avoided costs for QFs.

Q. Why do you suggest it might be fair to allow NM generation to be credited at default service rates when there is surplus to carry forward to a future period to be consumed?

A. A number of cost components go into default service rates. The low bid of the competitive energy supplier incorporates the wholesale market costs plus some considerable amount for hedging to turn those dynamic and ultimately uncertain market costs into a fixed price for fixed period, with the additional risk of uncertain total load and load shape to be served. Plus there is the competitive supplier's own overhead and profit. Beyond that there is the distribution utilities' cost of administering the procurement including regulatory approval, perhaps a bit of credit and working capital cost, and more significantly, RPS compliance costs. When suppliers bid on the default service load, it is net of net metered loads and transactions, so they aren't figuring on buying the surpluses from one month to sell back at mark-up in a later month. The utilities' cost of administering the default procurement doesn't vary incrementally with net metering flows and the recovery base is figured net of net metered loads, as it should be. Hence the main variable is RPS compliance costs, which are becoming more significant over time. If a NM customer-generator produces and sells RECs for all their generation, essentially monetizing and selling off the renewable attribute, then I think it would be fair for that customer to pay for RPS compliance costs (which might go to purchase their RECs) whenever they take power back from the grid over a billing period, even if they had NM surplus to carry forward. On the other hand if they don't produce RECs for their behind the meter and net consumption, then other default service load benefits by getting credit for that renewable generation pursuant to RSA 362-F:6, II-a at no cost. Thus for such a customer-generator, full default service credit for episodic surpluses against future consumption seems more than fair to other customers, since the contribution of having that customer pay for RPS compliance would likely be far less than the cost of purchasing RECs for all that NM generation. However, a single credit rate for NM PV gives no price signal the value of western oriented or tracking systems.

Finally it is important to note that all ratepayers benefit from the demand reduction induced price effect (DRIPE) of having what is essentially price taking net metered generation, which lowers the demand for wholesale market generation whenever it is producing power from what it would otherwise be. The New England wholesales markets, both day ahead and real time, clear a bid stack of supply offers at constant intervals of time. Whenever demand across wholesale meter points, the real time load obligation, drops from what it would otherwise be, whether as a result of energy efficiency, demand response, such as shifting load to lower cost hours, or distributed generation that doesn't bid into the supply market, that reduced demand will lower the market clearing price (subject to the bid increments), benefitting all ratepayers.

While the DRIPE used in the last Core Program docket for energy efficiency might approximate this value, another anecdotal indication of the magnitude of this effect comes from a March 15, 2016 Bloomberg news story about a new ICF International study that found that Solar PV would be depressing prices in wholesale power markets by as much as $2 Billion by 2019. For New England Bloomberg reported that "Generators stand to lose as much as $716 million in New England's auction, where demand for conventionally-generated power has been cut by 390 megawatts, according to ICF. It's a figure that takes into account both the amount of new solar expected to be in use by 2019, and estimates for the power lost when the sun isn't shining."[8] Unfortunately the source report doesn't seem to be publicly available, or at least I haven't been able to track it down, but what it describes as bad news for generators is also savings and good news for load and ratepayers.

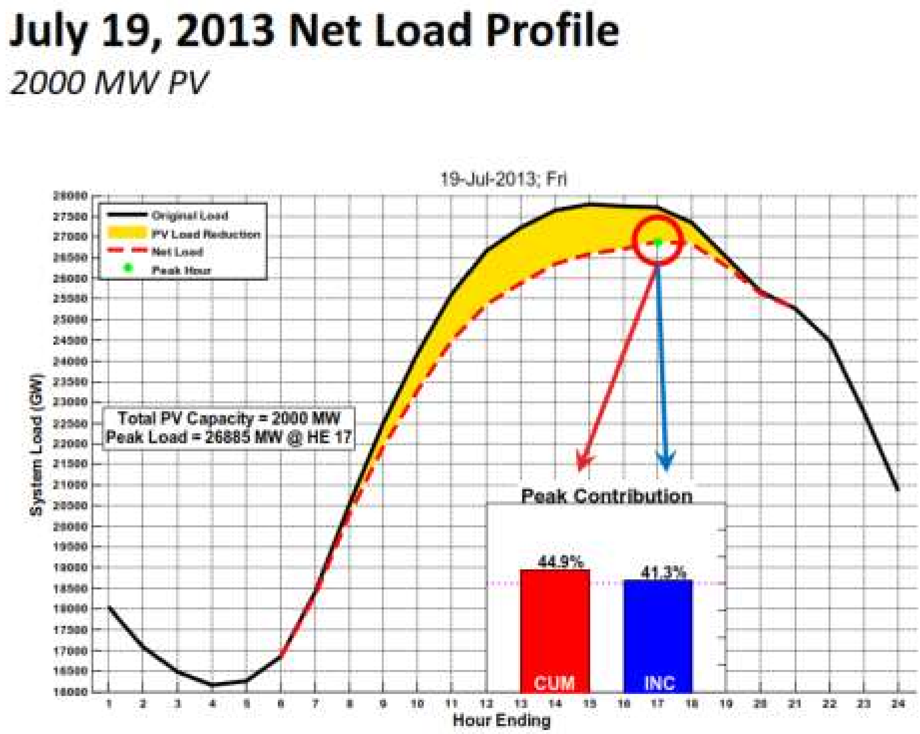
The DRIPE effect also matters in the forward capacity market, where even modest increments of increasing system peak demand can cause big increments of increase in next year's forward capacity auction clearing price as has recently been experienced. ISO New England, in this year's CELT report estimated that 40% of behind the meter (BTM) solar PV capacity (AC nameplate) was reducing the summer seasonal peak load in 2015 form what it would otherwise be. As the table below shows their 10 year forecast projects continued contribution to summer peak load reduction, albeit at a slowly declining rate as increasing amounts of PV slowly shifts the afternoon peak a bit later in the day each year (on average).[9]

3.1.2 - Forecast of Cumulative BTM Solar PV Estimated Summer Seasonal (July 1st) Peak Load Reduction by State

		Cumulative Total MW - Estimated Summer Seasonal Peak Load Reduction										
Category	**States**	**2015**	**2016**	**2017**	**2018**	**2019**	**2020**	**2021**	**2022**	**2023**	**2024**	**2025**
Behind-the-Meter PV	CT	61.0	92.1	123.9	153.6	181.0	207.7	230.6	247.6	262.8	275.7	288.2
	MA	194.0	249.4	295.6	312.6	320.4	324.0	327.9	332.5	337.1	341.8	346.2
	ME	5.4	7.3	9.0	10.6	12.2	13.7	15.2	16.6	17.8	19.1	20.3
	NH	6.8	12.7	16.7	18.7	19.9	21.1	22.2	23.4	24.6	25.8	26.9
	RI	2.5	3.7	7.0	11.3	15.2	18.7	20.6	21.3	21.8	22.3	22.7
	VT	44.2	57.8	67.4	75.4	83.0	90.5	97.7	104.5	110.9	117.1	123.3
Total	**Cumulative**	313.9	422.9	519.5	582.2	631.6	675.6	714.3	745.9	775.0	801.7	827.6
Estimated Summer Seasonal Peak Load Reduction - % of BTM AC nameplate		40.0%	39.4%	38.2%	37.3%	36.7%	36.1%	35.6%	35.2%	34.8%	34.5%	34.1%

[8] http://www.bloomberg.com/news/articles/2016-03-16/-2-billion-loss-for-generators-as-a-million-u-s-roofs-get-solar
[9] From tab 3.1.2, https://www.iso-ne.com/static-assets/documents/2016/05/2016_celt_report.xls

The cause of this effect can be illustrated with a slide from ISO New England's 2016 Solar Forecast,[10] seen below:



A series of slides illustrates how increasing level of BTM PV (with static load) slowly shifts the expected afternoon peak, which has moved from around 2-3 pm in the past to an hour ending around 4 or 5 pm more recently. However the growth of installed PV still has the effect of significantly reducing the peak from what it would otherwise be absent the PV so there is persistent benefit and value to the system and all ratepayers from continued avoidance of substantial investments in T, D & G capacity from what otherwise would be required.

V. Transmission

Q Please explain your ideal concept for a retail transmission tariff that supports NM and is fair to all customers.

A. The ideal would be to translate through to retail load the forward looking long-term marginal price signal that is charged at wholesale under FERC jurisdictional rates implemented by the ISO New England OATT (Open Access Transmission Tariff). While most of the current

[10] Slide # 80 https://www.iso-ne.com/static-assets/documents/2016/09/2016_solar_forecast_details_final.pdf

cost of operating the transmission grid consists of what are now relatively fixed and embedded costs from past investment in transmission capacity and capabilities, in the form of physical plant, nearly the entire revenue requirement for both PTF (pool transmission facilities) recovered through RNS (regional network service) rates and non-PTF or Local Network Service Rates are recovered through what is, in effect, a monthly demand charge, based on each distribution utility's share of coincident peak of the "local" transmission network that serves them. In New Hampshire's case, we are but a small part of the two local networks that serve us, namely National Grid that serves Liberty, which in March accounted for 28% of total New England network load, with NH network load constituting about 1% of that 28%, and NU serving Eversource and UES, which in March accounted for 35% of the NE network load, with NH load constituting 9% of that 35%.

Transmission rates are fully reconciling such that the full revenue requirement is always meet through apportionment of that revenue requirement by shares of monthly coincident peaks. With all other things being equal a reduction in NH share of coincident peaks will shift the vast majority of that "under-recovery" to ratepayers in other states. Ideally we would pass these shares of peak demand charges through to individual customers based on their individual contribution to these coincident peaks. As a matter of retail rate design NH does exactly the opposite. We translate what is a monthly coincident peak demand charge into a flat volumetric kWh charge for all customers with no temporal differentiation. This is pretty much the opposite of an appropriate price signal as it gives no transparency to cost causation and does nothing to promote economic efficiency and efficient investment in new or improved transmission capacity to accommodate growth in peak demands. Ironically, as I understand it, here in NH wholesale transmission charges are apportioned between rate classes based on each class' share of coincident peak before being translated to flat volumetric rates within each class. For the class there is an element of cost causation, but it is so dilute when translated to each individual customer in that rate class as to become invisible.

Q. Aren't most transmission investments for reliability as opposed to load growth?

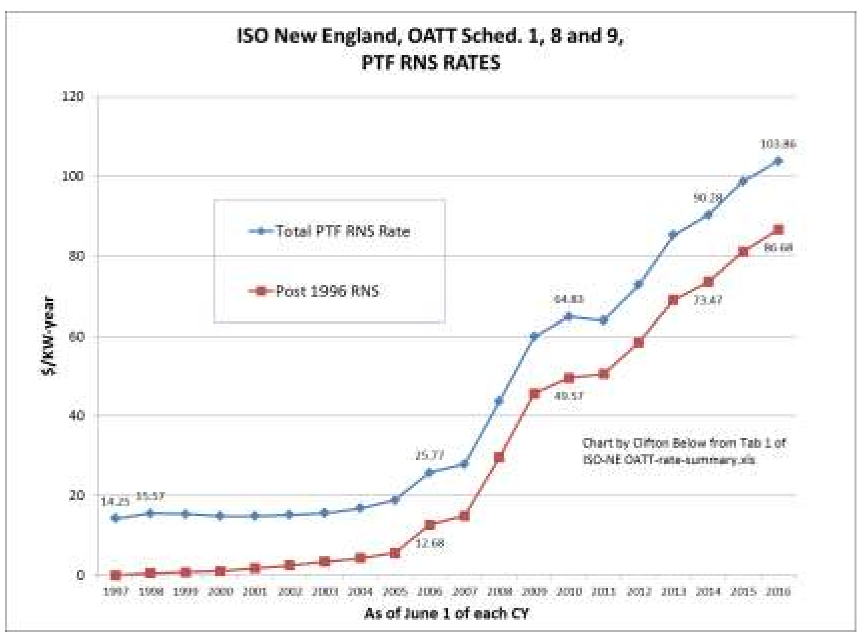
A. While there are variety of aspects to reliability, growth in peak demands is a central driver of reliability investments. Both transmission and distribution facilities tend to be under the greatest stress and risk of failure when they are most heavily loaded. Power lines sag the most and equipment like transformers tend to experience their greatest wear and tear and failure rates when they are most heavily loaded, especially when ambient temperatures are high, such as on hot summer days. To ensure reliability capacity margins need to be maintained.

In its 2015 Regional System Plan ISO-NE introduces the issues for northern New England Transmission as follows (p. 87):

> The transmission system throughout northern New England is limited in capacity; it is weak in places and faces numerous transmission security concerns. Underlying the limited number of 345 kV transmission facilities are a number of old, low-capacity, and long 115 kV lines. These lines serve a geographically dispersed load, as well as the concentrated, more developed load centers in southern Maine, southern New Hampshire, and northwestern Vermont.
>
> The two most significant issues facing the area have been to maintain the general performance of the long 345 kV corridors, particularly through Maine, and to ensure sufficient system security to meet demand. The region faces thermal and voltage performance issues and stability concerns. The system of long 115 kV lines, with weak sources and high real- and reactive-power losses, is exceeding its ability to integrate generation and efficiently and effectively serve load. Also, in many instances, the underlying systems of 34.5 kV, 46 kV, and 69 kV lines are exceeding their capabilities, and some are being upgraded, placing greater demands on an already stressed 115 kV system.

Q. Historically transmission costs have been a small part of retail rates, so why is this a concern now?

A. Perhaps so, but in recent years transmission rates in New England have risen rapidly and if current trends continue New Hampshire ratepayers will be paying proportionately more for new transmission investment than ratepayers in any other state. Let me explain with a few graphics. The chart at right shows the growth in RNS rates over the last two decades, during which the RNS rate has increased more than 7 fold.



Following are two slides from a 2015 presentation at NESCOE (http://nescoe.com/wp-content/uploads/2015/12/CLG_Dec2015.pdf)

Transmission Investment in New England

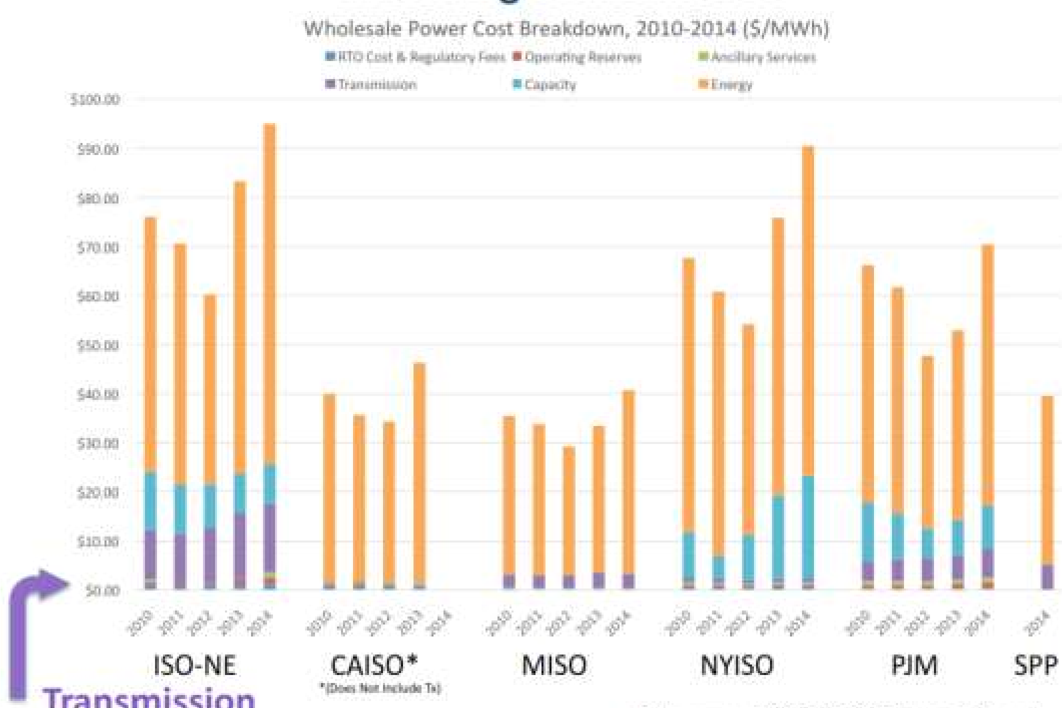
Since 2002, about $12 billion in reliability Tx placed in service, under construction or in planned/proposed phase

Cumulative Investment through June 2015	$7.2 billion
Estimated Future Investment through 2019	$4.8 billion

Source: ISO-NE

4

A Comparative Look: Market Pricing Components, Including Transmission



Data source: 2015 ISO/RTO Metrics Report

5

Note how the absolute size, proportion and rate of growth of transmission rates in ISO-NE compared with other organized markets. Now here is the kicker, New Hampshire has seen a substantial decline in its load factor from the decade ending in the year 2000, when it averaged 66.9%, to the decade ending in 2015, when it averaged only 57.1%, a nearly 10% drop. That means that in the past the average system load was about 67% of the summer NH coincident peak while it had dropped to about 57% in recent years. That means ratepayers are paying significantly more per kWh of electricity to support increasing T&D capacity for relatively fewer hours per year of high peak demands.

Now to make matter even worse, ISO-NE's latest load forecast (from http://www.iso-ne.com/static-assets/documents/2016/04/isone_fcst_data_2016.xls, tab 2) projects that New Hampshire gross coincident summer (annual) peak demand (kW, 50/50 forecast) will grow at a compound annual growth rate (CAGR) of 1.4% for the next decade compared with a CAGR of 1% for New England as a whole, only 40% higher than average. But wait, it gets worse, after netting out projected BTM PV and PDR (passive demand response, i.e. energy efficiency) from gross load, New England's projected peak demand CAGR falls to 0.2% while New Hampshire's only falls to 1.1%, more than 5 times the regional rate and more than double any other state, some of which are projected to see negative CAGR in net peak demand, like Vermont that is projected to have a –0.4% CAGR. That means we will have a disproportionately larger impact on the need for more transmission (and generation) capacity than any other state (cost causation) and our share of those costs will increase proportionately more than any other state.

And just to top this problem off our projected CAGR in load (GWh) is projected to be only 0.5%, while New England as a whole is projected to have a negative CAGR for load for the next decade of -.3%. (tab 10N) Most other states are projected to have negative or near zero net growth in load over the next decade. If it comes true that our peak demand grows at more than double the rate of our load over the next decade that will mean a further decline in our overall load factor and more costs for capacity (T, D and G), existing and new, per kWh. The best way to avert these rate increase impacts is likely to be to send appropriate price signals, aligned across all 3 rate components that there is value to reducing and shifting load off peak or generating more DG on those peaks, such as from western oriented and tracking solar PV. Reducing such growth in NH peak demand will benefit all ratepayers by reducing the drivers for new T & D investments and reducing our share of RNS, LNS and FCM charges for embedded costs from what they would otherwise be.

Q. So what are your tariff concepts for new default service NM tariffs and your RTP NM pilot?

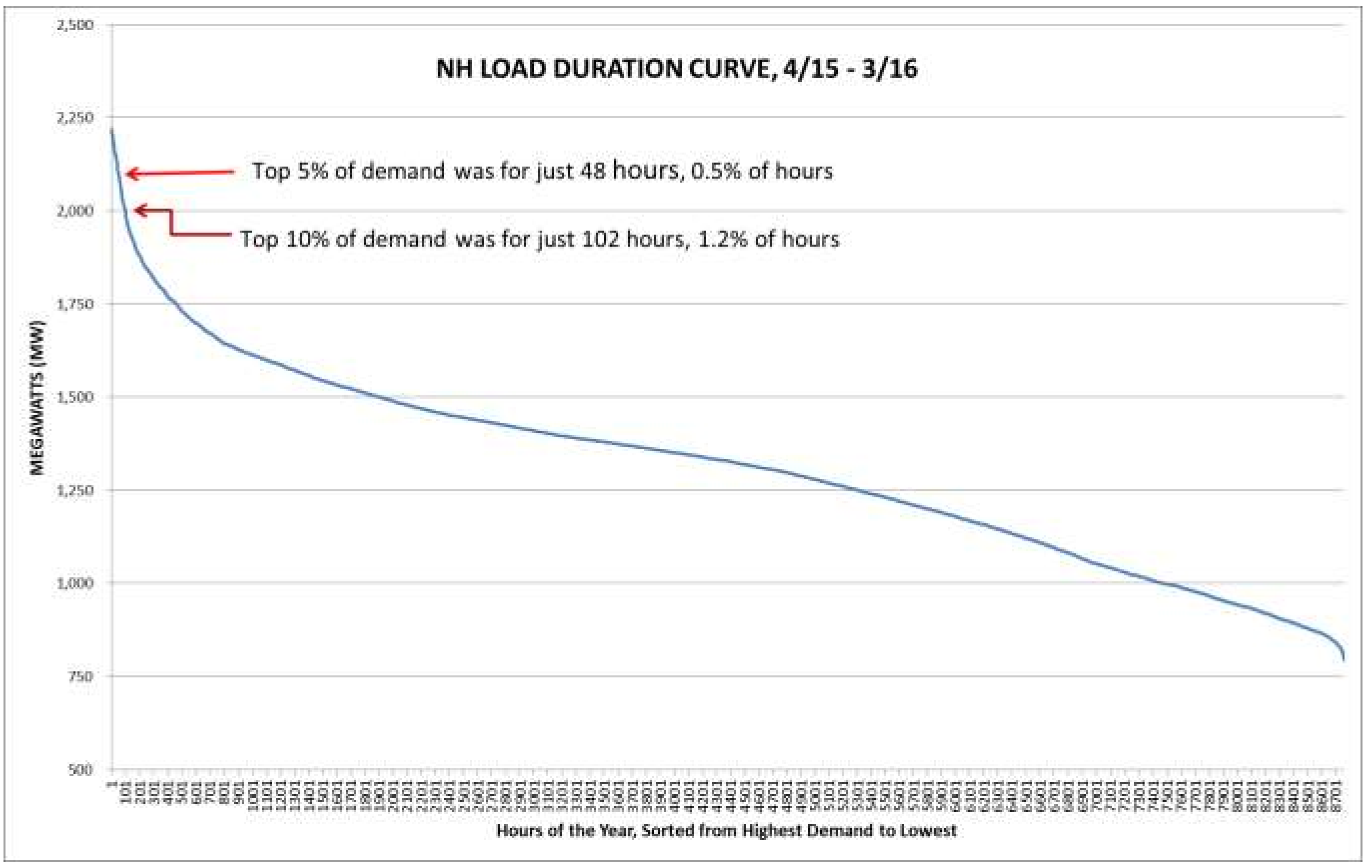
A. For default service, the simplest thing might to give monthly net exports of NM power full volumetric credit for transmission charges as an interim measure. The next step might be to redesign existing demand charges on a revenue neutral basis (before price response) to focus on the hours of the month or year when coincident peaks are most likely to occur. Volumetric rates can be similarly focused on a TOU basis. Ultimately interval data can sharpen the price signal. For our pilot where we would expect to have actual interval data for every load of any significant size, we would work with Liberty to design a tariff rider for participants that would be revenue neutral before price response and a provide credit (or additional charge) in proportion to the extent that each customer deviates from class average load shape relative to the target interval hours for either monthly coincident peak for annual likely high demand hours.

VI. Distribution

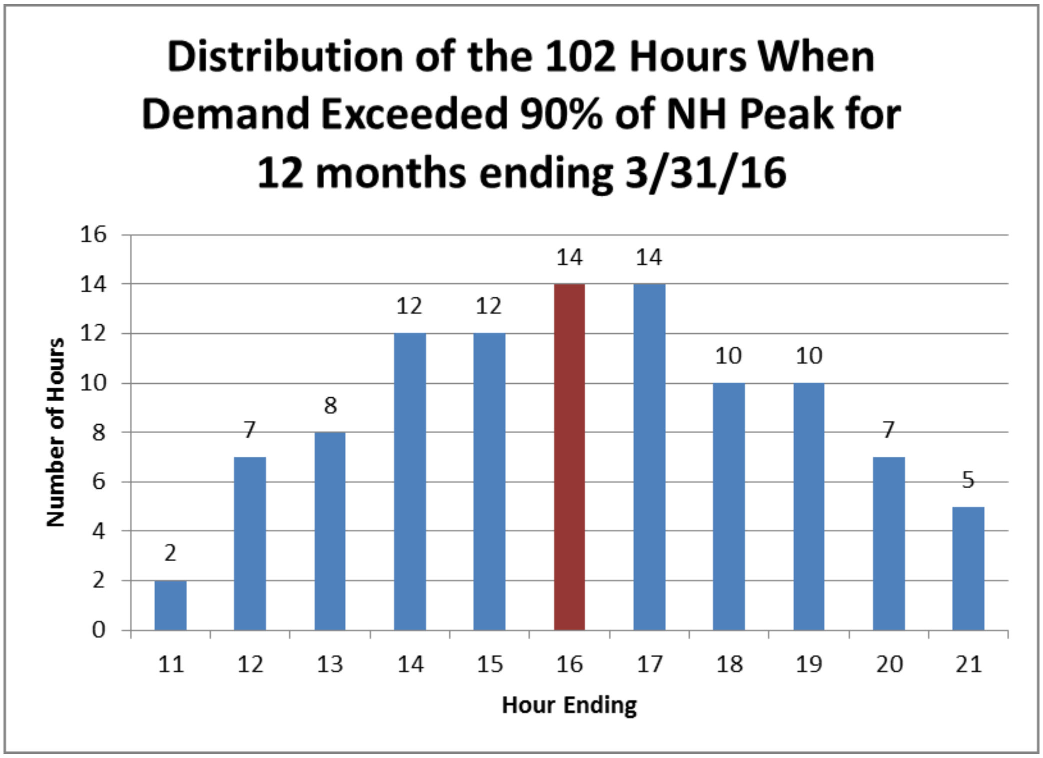
Q. How would proposed NM distribution tariffs be different from transmission rates?

A. Fundamentally there are many similarities to transmission in terms of how coincident peak demand growth stresses distribution systems and causes the need for future increased investment to increase capacity and reliability. However, it makes sense that NM customers who export power at certain times and take it back at other times or in other locations (such as with group NM or community solar) should pay to use the distribution grid to move power around town or "store" or bank it for later use. Therefore a simple interim step for use with existing meters and default service would be to simply charge regular distribution rates for any net imports in one month and not give distribution credit (volumetric or in dollars) for net monthly exports. A next step would be modify existing demand charges for larger C&I customers on a revenue neutral basis (before price response) so that they are concentrated during TOU or limited hours when high system coincident peak demand is most likely to occur. The same could be done for volumetric distribution rates. There will need to be volumetric/demand decoupling to make up revenues lost to price response that lowers peak demand. In the short term this may slightly increase rate for other customers, but in the long run it will help avoid growing peak demands and investments needed for more peak capacity and reliability investments for stressed distribution components. This will tend to improve load factors over time and lower distribution costs per kWh of load and demand for all customers from what they would otherwise be. The City of Lebanon would like to pilot some of these concepts as part of a RTP NM distribution tariff rider. This could be a collaborative effort with Liberty to improve the integration of non wire alternatives (NWA) into distribution system planning.

Below is a load distribution curve for NH. It is interesting to note the concentration of high demand in relatively few hours.



Of the 102 hours where demand exceeded 90% of peak, all of them were between the hours ending 11 am and 9 pm in the months of May-September. Below is a chart showing the distribution of those hours. The average peak demand for those 102 hours was just slightly later than the hour ending at 4 pm. Western oriented and tracking PV can have a very good coincidence with most of these hours.



VII. Other Rate and Regulatory Issues

If we get the price signals correct and there is no undue or unfair cost shifting with likely net benefits for all ratepayers from reducing peak demand growth and hence improving load factors and avoiding costly future investments for a very limited number of hours of high demand and stress, there is no good reason to limit such future Net Metering tariffs or the size of systems at any one location relative to the site load, especially if new NM systems continue to pay for the cost of interconnection.

There are issues with regard to how current inverters may affect power quality and system stability when NM generation starts to increase in proportion to load on local areas of the grid. There is great deal of effort going into technology and standards innovation to enable the use of smart meters that can improve grid stability and power quality rather than diminish it. Countries like Germany and states like California and Hawaii have already moved to better incorporate smart inverters, both those that act autonomously and those that can be addressed by the utility. I'd encourage the Commission and utilities to closely follow developments in this rapidly evolving field. The City of Lebanon would be interesting in possibly piloting the use of smart inverters as part of its RTP NM pilot. Here are three good resources on the topic:

1. A somewhat dated presentation at ISO-NE: https://www.iso-ne.com/static-assets/documents/committees/comm_wkgrps/prtcpnts_comm/pac/mtrls/2014/jul112014/california_smart_inverter_working_group.pdf
2. An excellent webinar set of slides from NREL that overview the issues with plenty of links for additional information: http://www.nrel.gov/tech_deployment/pdfs/2016-04-28-adv-inverter-deploy.pdf
3. And a recent joint white paper by EPRI and SEPA entitled "Rolling Out Smart Inverters: Assessing Utility Strategies and Approaches," found at: http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000003002007047

VIII. Pilot Proposal Next Step and Conclusion

Q. What do you see at the next steps in your proposal and do you have any concluding thoughts?

As you can see there are no actual proposed tariffs being submitted as part of this testimony. We are looking for approval of this concept and work with Liberty Utilities and other interested parties to collaborative on an next stage for further development and implementation., which may include seeking limited rule waivers necessary to enable aspects of the pilot. These could evolve into rules changes.

I can mention that both Competitive Energy Services, the City's current energy supply procurement vendor and Freedom Energy Logistics, which supports the Town of Hanover in their self-supply RTP for town loads through direct market participation, have expressed strong interest in collaborating in this pilot. I have meet with Peter Kulbacki, Director of Public Works for the Town of Hanover who is responsible for their RTP program and supports Sustainable Hanover's Green Power Challenge where participants bought 4.5 million kWh of Green-E certified power (RECs) last year (http://www.hanovernh.org/sites/hanovernh/files/uploads/new_faq_-_final.pdf). However some participants and the town have been frustrated in the lack of available local RECs and Peter believes there may be considerable interest in this kind of pilot, including the possibility of participation in community solar PPAs and even possibly some direct investment. We are planning further meetings after I file this testimony to explore the possibility of collaboration, which RSA 53-E expressly provides for.

Finally I'd like to mention that I have spoken with a couple of Dartmouth College faculty and an administrator about this possible RTP NM pilot in light of the College's recent announcement of the creation of the Arthur L. Irving Institute for Energy and Society, a major new interdisciplinary institute "to prepare future generations of energy leaders and advance humanity's understanding of the field, driving change in the intelligent production, supply, and use of energy." Their initial response was that this pilot could provide significant test bed research opportunities for the Institute, potentially involving faculty and students from theThayer School of Engineering, the Tuck School of Business, computer sciences, where Dartmouth has significant cybersecurity expertise, and a variety of humanities and social sciences. On the other hand that might just complicate things.

Q. Does that conclude your testimony?

A. Yes it does. Thank for your attention and interest. I could go on, but I'm out of time – real time peak load management challenges.